Service Date: January 25, 1983

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of the Application of	)	UTILITY DIVISION
PACIFIC POWER & LIGHT COMPANY	)	
for Authority to Adopt New Rates and	)	DOCKET NO. 82.4.28
Charges for Electric Service Furnished	)	
in the State of Montana.	)	ORDER NO. 4928a

APPEARANCES

FOR THE APPLICANT:

C. Eugene Phillips, Murphy, Robinson, Heckathorn & Phillips, One Main Building, Kalispell, Montana 59901

George M. Galloway, Stoel, Rives, Boley, Fraser and Wyse, 900 S.W. Fifth Avenue, Portland, Oregon 97204

FOR THE PROTESTANT:

James C. Paine, Montana Consumer Counsel, 34 West 6th Avenue, Helena, Montana 59620

FOR THE COMMISSION:

Calvin K. Simshaw, Staff Attorney

BEFORE:

HOWARD L. ELLIS, Commissioner, Presiding
JOHN B. DRISCOLL, Commissioner
CLYDE JARVIS, Commissioner
THOMAS J. SCHNEIDER, Commissioner

FINDINGS OF FACT

A. GENERAL

1. The Pacific Power and Light Company (PP&L, Company or Applicant) is a public utility furnishing electric service to consumers in the State of Montana.

2. Applicant's petition, filed April 27, 1982, requests this Commission's approval of rates and charges for electric service which are designed to produce an increase in annual gross operating revenues of $5,962,000 based on a test period of 12 months ended December 31, 1981.

3. The Commission subsequently issued Order No. 4881a in Docket No. 81.8.70 and Order No. 4916 in Docket No. 82.6.41, both of which affect the rates and revenue levels contained in Docket No. 82.4.28.

4. In order to incorporate the effect of the aforementioned Commission decisions, as well as to clarify the Company's proposals in Docket No. 82.4.28, the Applicant submitted to the Commission on July 9, 1982, revised testimony and exhibits for this Docket. Based on these revisions, PP&L determined that for the test year ended December 31, 1981, the Company requires additional revenues of $9,646,000 in excess of rates presently in effect. Of this amount, the Company estimates that $2,080,000 can be recovered from the Bonneville Power Administration (BPA) pursuant to the terms of the Company's Residential Purchase and Sale Agreement with BPA authorized by the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). Therefore, the revised tariff schedules are designed to produce a net revenue increase of $7,566,000 over the presently effective rates.

5. On May 25, 1982 the Commission issued a Notice of Filing and Proposed Procedural Schedule. On June 22, 1982 the Commission issued a Procedural Order.

6. The Procedural Order was amended to reflect the following schedule:

a. July 12, 1982: Final day for interested parties to intervene and provide PP&L with written discovery and data requests.

b. July 31, 1982: Final day for completion by PP&L of all answers and responses to discovery and data requests directed to PP&L by other parties.

c. September 22, 1982: Final day for completion and service upon PP&L and other parties of the prepared testimony and exhibits of all parties except PP&L.

d. October 6, 1982: Final day for written discovery and data requests directed to all parties by PP&L and intervenor data requests directed to parties other than PP&L.

e. October 18, 1982: Final day for completion of answers by all parties to discovery and data requests made by PP&L.

f. October 28, 1982: Due date for PP&L's rebuttal testimony.

g. October 29, 1982: Final day for any party which intends to introduce as evidence, data requests or other discovery as part of its basic case, to notify all parties of the specific data requests or other discovery it plans to so introduce.

h. November 3, 1982: Opening day of hearing in Docket No. 82.4.28.

7. On July 14, 1982, PP&L filed with the Commission an application, subject to rebate, for interim rate relief in the amount of $3,103,000, based on a test year ended December 31, 1981. On August 31, 1982, the Commission granted PP&L interim revenue relief in the amount of $2,648,000.

8. On October 21, 1982, the Commission issued a notice approving the combining, for hearing purposes only, of Docket Nos. 82.4.28 (General Rate Case) and 82.9.59 (BPA Pass-through).

9. The Montana Consumer Counsel (MCC) has participated in this Docket on behalf of the consuming public since the inception of these proceedings.

B. CAPITAL STRUCTURE AND ASSOCIATED COSTS

10. Applicant proposed the following capital structure and associated costs (PP&L Exh. RFL, Table 2-7):

Description	Ratio	Cost	Weighted Cost
Long-Term Debt	52 .9%	9.25%	4.89%
Preferred Stock	9.8	9.94	.97
Deferred Taxes	2.0	--	--
Common Equity	35.3	17.50	6.18
			12.04%

11. MCC proposed the following capital structure and associated costs (MCC Exh. CMS-1):

Description	Ratio	Cost	Weighted Cost
Long-Term Debt	55.3%	9.25%	5.12%
Preferred Stock	13.8	9.94	1.37
Common Equity	30.9	14.00	4.33
			10.8 %

Applicant's Presentation

12. Applicant proposed to utilize its target ratios in the capital structure, adjusted to reflect the addition of deferred taxes amounting to 2.0 percent of the capital structure. The Applicant's target ratios are: 54 percent long-term debt, 10 percent preferred stock, and 36 percent common equity (PP&L Exh. 2-T, p. 4).

13. Dr. Caroline Smith used the end of period capital structure at December 31, 1981 as a starting point and then made some adjustments. Dr. Smith does not include deferred taxes in the capital structure. In Order No. 4881a, Docket No. 81.8.70, the Commission accepted Mr. Hess' recommendation to deduct deferred taxes from rate base, as the Commission has consistently done in previous decisions because deferred taxes do not affect the overall cost of capital. In its interim filing in this Docket, PP&L, pursuant to the Commission's interim rules, followed the methodologies approved by the Commission in Order No. 4881a. On page 2 of his testimony, Mr. Hess agreed that the Company had conformed to his previous recommendation as accepted by the Commission in Order No. 4881a, and Mr. Hess proposed that similar treatment be accepted by the Commission in this proceeding.

14. Pursuant to stipulation by PP&L and MCC, Dr. Smith retracted her testimony concerning the debt-equity exchange and its effect on capital structure and costs. Correspondingly, PP&L agreed not to update its capital structure and costs after December 31, 1981. Appropriate ratemaking treatment for the debt-equity exchange will be addressed in Docket No. 82.7.53, the

nuclear plant abandonment case. (Letter from George M. Galloway to James C. Paine, dated October 28, 1982.)

15. Dr. Smith also adjusted the common equity to eliminate the portion invested in subsidiaries other than the electric utility operations (MCC Exh. 2, pp. 5,6). MCC argues that debt is dedicated to the utility and does not support nonutility operations.

16. This present Docket contains a proposal concerning subsidiaries as they pertain to the capital structure. In the PP&L system, the use of parent debt to finance subsidiary investments does not occur until the second tier of the system is reached, as described in MCC's testimony in Docket No. 81.8.69. Mr. Lanz' capital structure includes all of PP&L's consolidated capital, except for the subsidiary long-term debt.

> Under Mr. Lanz' approach, if the subsidiaries earn an equity return on the equity capital investment of PP&L, as recorded on its books of account, then the overall consolidated equity return will exceed the estimated consolidated cost of equity capital and the Company will have derived a windfall at the expense of utility ratepayers whose debt capital has been improperly attributed to subsidiary operations. (MCC Exh. 2, p. 71)

17. In establishing PP&L's utility capital structure, MCC removed both the subsidiary debt and subsidiary equity capital from the consolidated capital structure and assigned them directly to those operations. This same approach was adopted by the Commission in Docket Nos. 80.8.67 and

81.8.70. MCC maintains that failure to reduce the equity capital of the consolidated enterprise by the investment in its subsidiaries results in an excess return to the enterprise (MCC Exh. 2, pp. 71-73).

18. The Commission concurs with the arguments set forth by Consumer Counsel such that debt is dedicated to the utility and does not support non-utility operations. Thus, components of the capital structure which are related to nonutility subsidiaries must be eliminated. The Commission finds the capital structure proposed by Dr. Smith to be appropriate in this Docket.

Cost of Debt

19. The debt capital is not a contested issue in this case. The cost of long-term debt is based on the embedded debt cost at December 31, 1981, and has been determined to be 9.25 percent by both MCC and the Applicant (PP&L Exh. 2, Table 2-7 and MCC Exh. 2, CMS-1). This cost is acceptable to the Commission.

Cost of Preferred

20. The cost of referred stock is not a controverted issue in this case. The cost of preferred stock is based on the embedded cost of preferred shares outstanding at December 31, 1981, and has been determined to be 9.94 percent by the Applicant and MCC (PP&L Exh. 2, Table 2-7 and MCC Exh. 2, CMS-1). This cost is acceptable to the Commission.

Cost of Common Equity

21. Applicant uses the following methodologies in determining a return on equity of 17.50 percent:

> (a) Discounted cash flow (DCF) basis. Concerning the dividend yield portion of the DCF analysis, the following excerpt describes Mr. Lanz' conclusion:
>
> > I believe that given the pressures on interest rates expected in the year ahead, and the upward trend in Treasury Bill futures, that 12 to 13 percent is a reasonable estimate of the Company's dividend yield during the period which rates will be in effect. I have chosen a value near the high end of the recent yield range because of my belief that general economic conditions, Treasury deficits and subsequent borrowings, as well as uncertainty facing the Northwest utility industry, will combine to require higher yields thus higher returns on common equity securities.
> > (PP&L Exh. 2-T, p. 8)

Concerning expectations of growth in dividends, Mr. Lanz used the predictions for PP&L by Value Line, Salomon Brothers Electric Utility Common Stock Market Data, and ARGUS Electric Utility Rankings for the time period 1980 to 1987 collectively to determine a growth range of 4.5 to 6.5 percent (PP&L Exh. 2-T, p. 8).

Mr. Lanz concludes:

> Classic discounted cash flow theory states that the required cost of equity is equal to dividend yield plus growth in dividends. Based on the foregoing analysis, I believe that 16.5 percent to 19.5 percent would realistically cover the range of possible equity returns, with 17.5 being a reasonable equity cost within the range.
> (PP&L Exh. 2-T, p. 9)

(b) Market/book relationship. On Table RFL 2-6, Mr. Lanz shows market-to-book ratios for 20 electric utilities. In analyzing this data, Lanz testified:

> The Company has a market to book ratio of 84 percent compared to the average of 72 percent for the comparable companies. This ratio, which on the surface appears to reflect investors' confidence and a generally favorable assessment of the Company compared to the average, is misleading. It is misleading due to the fact that since July, 1981, the Company's market to book ratio has fallen from 96 percent to its current level of 84 to 86 percent. It appears the Company has been reevaluated by the investor, and his confidence has been shaken, thereby requiring a higher return on investment.
> (PP&L Exh. 2-T, p. 11)

(c) Analysis of comparable companies. Mr. Lanz conducted a study of Baa utilities comparing their current yields and growth in dividends to determine a market capitalization rate. Lanz concluded:

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(c) Analysis of comparable companies. Mr. Lanz conducted a study of Baa utilities comparing their current yields and growth in dividends to determine a market capitalization rate. Lanz concluded:

> Based on my comparable company analysis, Baa utilities are requiring returns on their equity in the range of 15.98 percent to 18.92 percent with an average value of 17.65 percent. I believe that within this range, the Company's perception by the investment community is no worse than average and therefore a reasonable return would be in the range of 16.7 to 17.7 percent.
> (PP&L Exh. 2-T, pp. 11-12)

(d) Reasonable differentials between the cost of common equity and cost of long term bonds. In this analysis, Mr. Lanz proposed that common stock is less secure than bonds and, therefore, demands a higher rate of return to compensate for a higher risk factor. Lanz testified the following:

> Studies have shown an historic spread differential of more than 300 basis points between the cost of long term debt and common equity. If one assumes an approximate 250-300 basis point spread between common equity and long term debt, then equity costs based on the October, 1981 issue would be approximately 21.1 to 21.6 percent. Moreover, new utility bonds are currently being issued at cost rates in the range of 15 to 17 percent. A 250-300 basis point spread differential would place the required equity returns in the 17.5 percent to 20 percent range.
>
> (PP&L Exh. 2-T, p. 10)

Mr. Lanz summarized his analysis by testifying the following:

> After analyzing the factors which affect the Company's stock, and based on my analysis of the cost of common equity on a comparable company, differential over debt, and discounted cash flow basis, I believe that 17.5 percent is a conservative and reasonable cost of common equity for the period rates will be in effect.
>
> (PP&L Exh. 2-T, p. 12)

22. MCC uses the following methodologies in arriving at a return on equity of 14.0 percent:

a. Application of discounted cash flow (DCF) techniques to Applicant's financial data. The DCF methodology yielded a range of return on equity of 13.75 to 14.25 percent.

1. Dividend yields for 95 electric and combination electric and gas utilities traded on the New York Stock Exchange were calculated on an average price basis for the six months from January through June, 1982. The average dividend yield for the 95 companies is 12.2 percent. (MCC Exh. 2, Appendix B, p. 3)

2. Expected dividend growth was calculated by examining growth rates in dividends, earnings and book value over a ten year period for the companies

in the study. The weighted average growth for these companies was 3.3 percent during that time period. (MCC Exh. 2, Appendix B, pp. 4-5)

3. The model used by MCC was used to identify differences between the cost of equity for the Applicant and the industry as a whole. (MCC Exh. 2, p. 17)

b. The reasonableness of the DCF approach was examined by performing a comparable earnings study. A tabulation of earned rates of return for 95 electric and combination utility companies indicated that average earnings on equity for the 1970-1980 period were in the 11 percent to 12-plus percent range. (MCC Exh. 2, p. 52)

23. Both MCC and PP&L used a DCF model to determine the cost of equity in this proceeding. In each model there are elements which are based upon the judgment of the particular witness. Upon viewing the two models presented, major differences appear. MCC used a large number of companies (95) for analytical purposes, while PP&L relied on projected estimates for Treasury Bill and interest rates to determine dividend yield and various analysts' forecasts of PP&L growth expectations. (PP&L Exh. 2-T, p. 8) This Commission has historically disallowed unsubstantiated projections of future conditions. This Commission also has consistently preferred the process of evaluating many companies in the DCF model so that factors which are unique to a particular firm can be eliminated. The Commission, therefore, finds the MCC approach to DCF analysis preferable to that of the Company.

24. Concerning the Cost of Common Equity, PP&L recommends 17.50 percent return and MCC proposed 14.00 percent return on equity. The Commission feels that MCC's growth figure for PP&L was somewhat low based on the Company's actual dividend growth of 4.5 percent (PP&L Table RFL 2-6) and the weighted average growth of 3.3 percent of the 95 companies (MCC Exh. 2, Table B-4).

25. The Commission having considered the above factors, determines that the acceptable rate of return on common equity is 14.50 percent. This is slightly above the upper end of the range recommended by Dr. Smith.

Rate of Return

26. Based on the findings for long-term debt, preferred stock, and common equity, the following capital structure and costs resulting in a 10.97 percent overall rate of return are determined appropriate:

Type	Capital Structure	Cost	Weighted Cost
Long-Term Debt	55.3%	9.25%	5.12%
Preferred Stock	13.8	9.94	1.37
Common Equity	30.9	14.50	4.48
Overall Cost of Capital	100.0%		10.97

C. RATE BASE

27. The following rate base proposals were submitted. The final column is the rate base approved by the Commission.

28. Consistent with previous Commission decisions, both PP&L and MCC proposed a 1981 average rate base, adjusted to include certain known and measurable 1982 changes. One of the primary considerations of the Commission in rate base decisions has always been proper matching of test year income with the plant that produced that income. The Commission, therefore, determines in favor of a 1981 average rate base, adjusted for certain known and measurable 1982 changes.

Net Plant in Service

29. PP&L proposed an average net plant in service, "adjusted to reflect the availability of the Company's Whiskey Run Wind Generation Unit and the Malin-to-Midpoint 500 KV Line Project for the entire test period, which is consistent with the 40-year production cost study (PP&L Exh. 5-T, p. 13)." MCC made no adjustments to the Company's proposed average net plant in service. Since the Company's proposed figures comply with the accepted methodology of average year rate base, the Commission determines the proper amount of net plant in service to be $68,986,000.

Plant Held For Future Use

30. The Company's proposed rate base included $106,000 of plant held for future use. In order to comply with the Commission's Interim Rules, PP&L proposed an adjustment to remove $41,000 of this amount in their interim application. This adjustment was made to comply with the methodology approved by the Commission in the previous order, Order No. 4881a of Docket No. 81.8.70. MCC proposed no further adjustment to this account. PP&L’s interim adjustment was for property not expected to be placed in service prior to the period 1990 to 2000. Current ratepayers should not be burdened with carrying costs of property which will not be used in the imminent future. The Commission, therefore, finds the proper amount of plant held for future use to be $65,000.

Acquisition Adjustment

31. Applicant's proposed rate base included an acquisition adjustment in the amount of $1,000. In order to comply with the Commission's Interim Rules, PP&L proposed an adjustment to remove the total amount in their interim application. This adjustment was made to comply with the methodology approved by the Commission in the previous order, Order No. 4881a of Docket No. 81.8.70. MCC proposed no further adjustment to this account. PP&L's interim adjustment represents the amount paid for property in excess of its original cost. Renewal of this acquisition adjustment is consistent with past Commission action; therefore, the Commission finds that the $1,000 acquisition adjustment should be eliminated.

Nuclear Fuel

32. PP&L proposed a 1981 average level figure for nuclear fuel. MCC proposed no further adjustment to this account. The Commission agrees that the Company's proposal reflects the preferred average rate base methodology, and the proper amount of nuclear fuel included in rate base is $21,000.

Customer Advances For Construction

33. PP&L proposed a 1981 average level figure for customer advances for construction. MCC proposed no further adjustment to this account. The Commission agrees that the Company's proposal reflects the preferred average rate base methodology. The proper amount of customer advances for construction deducted from rate base is $297,000.

Materials and Supplies

34. PP&L proposed a 1981 average level figure for materials and supplies. MCC proposed no further adjustment to this account. The Commission agrees that the Company's proposal reflects the preferred average rate base methodology; therefore, the proper amount for materials and supplies included in rate base is $1,414,000.

Cash Working Capital

35. "... The development of net cash working capital supplied by investors, as assigned and allocated to Montana, is based on a lead lag study performed by the Company for the 1981 test period (PP&L Exh. 5-T, p. 14)." MCC made no adjustment to the Company figure. The Commission finds that the proper amount of cash working capital to be included in rate base is $406,000.

Extraordinary Property Losses

36. PP&L proposed a 1981 average level figure for extraordinary property losses. MCC proposed no further adjustment to this account. The Commission agrees that the Company's proposal reflects the preferred average rate base methodology, and the proper amount of extraordinary property losses included in rate base is $15,000.

Unamortized Leasehold Improvements, Etc.

37. PP&L proposed a 1981 average level figure for unamortized leasehold improvements, etc. MCC proposed no further adjustment to this account. The Commission agrees that the

Company's proposal reflects the preferred average rate base methodology. The proper amount of unamortized leasehold improvements, etc., included in rate base is $290,000.

Weatherization- Interest Free Loans

38. PP&L proposed a 1981 average level figure for weatherization-interest free loans. MCC proposed no further adjustment to this account. The Commission agrees that the Company's proposal reflects the preferred average rate base methodology; therefore, the proper amount of weatherization-interest free loans included in rate base is $384,000.

Customer-Contributed Capital

39. The Applicant proposed to include deferred taxes at zero cost in the cost of capital and include these customer contributed funds in rate base. MCC proposed to eliminate the deferrals from rate base, as is consistent with the Hess proposal in Docket No. 81.8.70. The Commission, consistent with prior decisions, finds the removal of deferred taxes from rate base to be correct. The proper amount of customer-contributed capital deducted from rate base is $1,900,000.

Unamortized Investment Tax Credits

40. The Company proposes that unamortized investment tax credits should be restored on a modified flow-through basis over an eight-year period. Mr. Hess proposed a "flow-through of one-half of the investment tax credits that can be utilized in the test year after adjustment for any rate increase authorized (MCC Exh., 3, p. 7)." The Commission, consistent with prior decisions, finds that unamortized investment tax credits are properly deducted from rate base and that MCC's proposal is preferred. Based upon an adjustment in the rate base and the revenues and expenses sections, the amount of tax credits to be deducted is increased. In order to achieve an average adjustment, one-half of the net expense adjustment is deducted from rate base. The proper amount of unamortized investment tax credits deducted from rate base is $259,000.

Sale of Malin-Midpoint Tax Deductions

41. Consistent with his testimony in Docket No. 81.8.70, Mr. Hess proposes that the proceeds from the sale of these federal tax deductions "be amortized above the net operating revenue line and that the unamortized balance be deducted from rate base (MCC Exh. 3, p. 7)." Hess continues:

> I recommended that the proceeds related to investment tax credits be amortized over a period of 5 years and that the remainder be amortized over a period of 30 years in reverse order of the tax deductions associated with lease payments less interest income. (MCC Exh. 3, P. 7)

42. The Company proposes that the transmission line should be treated as if it were still entirely owned by PP&L and that ratepayers should be credited with tax benefits associated with the transmission line in the same fashion as if the lease had not been entered into. Mr. Watson disagreed with the Hess proposal "for the following reasons: (1) it is contrary to the intent of ERTA and its leasing provisions; (2) it significantly impacts the economics of the transaction to the extent that the transaction becomes uneconomical for the Company; (3) the proposed treatment is in conflict with legislation that has passed the Senate Finance Committee in the proposed technical corrections act of ERTA." (PP&L Exh. 22-T, pp. 26-27)

43. After reviewing the evidence brought forward in this Docket, the Commission determines that the tax benefit sale will be treated as a sale of utility assets for ratemaking purposes. The Commission, therefore, finds in favor of the Hess approach, and this order will reflect MCC's various adjustments relative to this sale of tax deductions. The proper amount of rate base reduction from the sale of Malin-Midpoint tax deductions is $939,000. The Commission makes this determination while keeping in mind that an adverse Treasury ruling would necessitate a review of this decision.

Total Rate Base

44. As a result of the various adjustments, the Commission finds the proper amount of total 1981 average rate base, adjusted for known and measurable changes, to be $68,445,000.

D. REVENUES, EXPENSES, AND REVENUE REQUIREMENT

45. Mr. Stephen E. Pearson sponsored exhibits and testimony which detailed the cost of service and average rate base amounts which support the revenue increase of $7,183,000, prior to attrition considerations, requested by the Applicant and based on an overall rate of return of 12.04 percent. He indicated that the Company utilized a 1981 historical test period as a basis for its filing and made various 1982 adjustments. Mr. Pearson concluded that, based on the test period ending December 31, 1981, the Company would require additional revenues of $7,183,000 in order to earn an overall return of 12.04 percent.

46. Mr. George F. Hess, a witness for MCC, presented testimony and exhibits on the cost of service and the proper rate base. Mr. Hess urged the use of an average 1981 rate base, as was also proposed by the Company, adjusted for certain known and measurable 1982 changes. He prepared a series of schedules and presented related testimony which culminates with the change in revenues required to produce the 10.82 percent rate of return recommended by Dr. Caroline Smith. Mr. Hess concluded that, based on the 1981 average test year, the Company requires additional permanent revenues of $2,266,000.

Operating Revenues

Investment Tax Credit Transfers

47. In order to comply with the Commission's Interim Rules, PP&L proposed an adjustment to operating revenues to include $24,000 in their interim application to reflect the recognition of interest earned by the Company resulting from the transfer of investment tax credits to subsidiary nonutility operations. This adjustment was made to comply with the methodology approved by the Commission in the previous order, Order No. 4881a of Docket No. 81.8.70. MCC proposed no further adjustment to this account. Mr. Hess testified:

> In Order No. 4881a the Commission adjusted operating revenues to give the utility credit for utility investment tax credits transferred to non-utility operations in the past. The Commission reasoned that the transfer represented a loan from utility to non-utility operations for which the utility operations should be compensated. I did not propose

> that adjustment in Docket No. 81.8.70, but I agree that it is reasonable. (MCC Exh. 3, pp. 6-7)

The Commission feels that since investment tax credits are being loaned to nonutility operations, the electric utility is entitled to earn interest on the transfer. The Commission finds that the overall rate of return granted in this case should determine the interest which shall be earned on the transfer of investment tax credits. This adjustment increases revenues by $24,000 ($7,412,114 X 10.97% X .029).

Normalized Firm Sales

48. In its filing, PP&L submitted the results of the production cost study containing the firm power sales under contract only for calendar year 1982 and disposing all remaining surplus power on a nonfirm basis. The Company felt that normalized treatment of firm power sales for the 1981 test year would be unreasonable and inappropriate and that the proposed method would be more indicative of conditions that will exist during the period in which the proposed rates will be in effect. Mr. Steinberg testifies:

> In previous rate filings the Company disposed of all additional generation through firm power sales to wholesale for resale customers, hence the name given to this procedure is firm sales normalization adjustment.... Whereas in the past several years the Company has enjoyed a favorable position in the wholesale for resale market, our position in the present market has greatly deteriorated to the point that it is beyond reason to make a firm sales normalization adjustment in this proceeding. (PP&L Exh. 21-T, pp. 1-2)

49. The Company included all firm power sale commitments for 1982 that were known at the time that the Company's case was prepared, which was during February and March of 1982. The Company reported that during the next seven months since the case was prepared, the Company had not sold any additional firm power (PP&L Exh. 21-T, p. 3). Mr. Steinberg claimed that the most significant factor impacting the Company's ability to consummate firm power transactions is the large amount of surplus power in the northwest and in areas outside the region due to low load growth (PP&L Exh. 21-T, p. 4):

> Given the regional surplus energy glut and the reality of the economic principle that suggests it is better to sell something and make a small profit compared to not selling it at all, one can appreciate the position of potential buyers as articulated by them - why should we buy firm power when we can buy nonfirm power at substantially lower prices? (PP&L Exh. 21-T, p. 6)

50. MCC witness Hess disagreed with the Company's proposal concerning firm sales and adjusted operating revenues in the amount of $440,000 to reflect the normalization of firm sales. Although Mr. Hess conceded that the Company is not likely to sell firm power presently at the price advocated by Mr. Hess in his normalization calculations (TR, p. 448), he emphasized that it would be inappropriate to "update the test material to reflect what we hope are the low points in economic conditions being experienced in 1982 (TR, p. 441)." Hess continued:

> It's not just the normalization adjustment. Resources would be different, not only for PP&L but the area, and then we would still have to ask ourselves a question when we got through making all those changes whether a test year should reflect 1982 economic conditions.... I had to decide whether we should recommend staying with the 1981 test year and adjusting, as PP&L has always adjusted in the past, or recommending that this Commission base rates on the basis of 1982 depressed conditions, and I don't believe that that's the proper way to go. (TR, pp. 441, 443)

51. Consistent with previous Commission decisions, the Commission finds the normalization approach proposed by Mr. Hess concerning firm sales to be appropriate in this proceeding. The Commission feels that normalization is a proper regulatory method in smoothing out the high and low periods of firm sales and that to recognize particular economic conditions in favor of normalization as a whole would only serve to weaken the normalization process. The Commission accepts the adjustment of Mr. Hess in the amount of $440,000 as an increase to operating revenues.

52. In this proceeding, the Commission chose not to make any regulatory adjustments for excess capacity; however, it is clear that as long as this Commission allows surplus generating capability into rate base, and as long as that surplus is being sold at a loss, the ratepayers are paying the difference between cost of generation and revenue from off-system sales. Since our region is

looking at the probability of a long-term surplus, this Commission believes strongly that a concerted cooperative effort will be necessary to recover some of the fixed costs associated with new thermal plants. In future cases, if cooperative efforts do not provide a remedy, this Commission may consider various actions to remedy the situation. For instance, the Commission may consider disallowing excess generating capability in the rate base, thus allowing the stockholders of PP&L to experience the cost of subsidizing off-system sales losses. Another possible approach would be to allow the excess in the rate base and impute revenues to off-system sales equal to PP&L's Long-Run Incremental Cost or the full revenue requirement of existing thermal facilities. Such alternatives were seriously considered in this Docket, but the Commission decided rather to give the Applicant fair warning and offer the opportunity for open discussion of this serious problem which affects both ratepayers and stockholders. A rational regional pricing strategy is critical from both the investor and ratepayer perspectives.

53. The above adjustments to operating revenues result in present revenues of $23,644,000 ($23,180,000 + $24,000 + $440,000).

Expenses

Miscellaneous Expenses

54. In order to comply with the Commission's Interim Rules, PP&L proposed adjustments to various expense accounts such as institutional advertising, general coal expense, sale of tax benefits, and subsidiary investment tax credit in their interim application. This was consistent with the methodologies approved in Order No. 4481a, Docket No. 81.8.70. Concerning institutional advertising, MCC made no further adjustment, and the Commission finds this adjustment to be consistent with previous decisions. The Commission determines that institutional advertising expense should be decreased by $8,000.

Sale of Tax Benefits

55. MCC witness Hess recommended the amortization of the proceeds from the sale of tax benefits. When PP&L received authorization for the sale of tax benefits, this Commission clearly

indicated that the proceeds from the sale of utility assets would be subject to a ratemaking determination. The Commission is not persuaded by the Company's argument that Montana ratepayers are no worse off under its proposal than if the transaction had never occurred. The proposal presented by Hess of amortization of the proceeds over five and thirty years appeals to the Commission as an even handed sharing of benefits between the Company and its ratepayers. The adjustment of ($202,000) is accepted by the Commission. A strong concern of PP&L is that future regulations from the Treasury will forbid the ratemaking treatment proposed by Hess. Should regulations be issued which indicate that the ratemaking treatment adopted by this Commission is improper, the Commission will review the matter.

Captive Coal

56. MCC witness, Dr. J. W. Wilson, proposed an adjustment to eliminate the profit from Jim Bridger Coal which exceeded a rate of return of 16 percent. Dr. Wilson calculated that in 1981 the Bridger Coal Mining Joint Venture had an equity return of approximately 355 percent and the total return (equity plus debt) was approximately 37.9 percent. The equity return realized by PP&L's subsidiary (Pacific Minerals, a subsidiary of NERCO) was calculated to be approximately 58.5 percent and the total return (equity plus debt) was approximately 29.75 percent. (MCC Exh. 1, JW-1, p. 1 of 1)

57. Dr. Wilson judged these profits as "extraordinary" and based his conclusions on two studies. First, he examined recent and projected rates of return for the six independent coal companies for which he obtained public financial data. Second, Dr. Wilson performed a study of profit rates earned by unregulated firms throughout the industrial sector of the U.S. economy. (MCC Exh. 1, pp. 9, 11)

58. The results of both of Dr. Wilson's studies indicated that a proper rate of return for the Bridger Operation would be between 15 and 16 percent. The related captive coal adjustment reflects what Dr. Wilson professes to be a reasonable rate of return for the Bridger Coal Company based on his "rate of return" methodology.

59. The Company's methodology concerning the captive coal issue was the "market price" approach. Mr. Watson and Mr. Grundmann presented evidence that an independent, competitive coal market exists on which Pacific could have procured coal in lieu of entering into the Bridger contract, and that the terms of the Bridger contract, and the price paid pursuant to it, compare favorably with what would have been available on the open market. (PP&L Exh. 22-T, p. 12; 23-T, p. 11)

60. Mr. Watson drew the following conclusions:

> (1) Bridger's contract price for coal sold to the Company in 1982 was more favorable to electric ratepayers than 25 of the 27 other supply arrangements for which data was available for 1982, both on the basis of cost per ton and cents per million Btu; (2) Bridger's contract price amounted to 80 cents per million Btu delivered, compared to an average price, FOB mine, for the other 27 sales during 1982 of 135 cents per million Btu. The average cents per million Btu associated with other long-term coal sales made from January through June, 1982, from the Montana and Wyoming coal region is approximately 1.7 times the price charged the Company for coal deliveries made from the Bridger Coal Company. (PP&L Exh. 22-T, pp. 15-16)

61. Mr. Grundmann analyzed the Bridger coal contract and concluded that not only did it appear to be the product of a negotiation process, but if anything, it was slightly more favorable to the utility purchaser and its ratepayers than the seller. (PP&L Exh. 23-T, pp. 14, 16, 36) With regard to a comparison of the average delivered price of coal from other Montana and Wyoming sites, Mr. Grundmann determined the following:

> For the third quarter 1982 time frame, I found the following based on the cost per MMBTU:
>
> First, that the average delivered price of all of the proposals is still almost double (183 percent) the actual price for the Bridger Contract, and any individual proposal is at least 58 percent greater. Second, even if a comparison were to be made on a mine-mouth basis (which, again, I do not believe is appropriate) the average FOB mine price of all of the proposals is almost 10 percent higher than the actual price for the Bridger Coal. (PP&L Exh. 23-T, pp. 19-20)

62. The Company attacked Dr. Wilson's adjustment (and rate of return methodology in general) on three main fronts: (1) interpretation of the Montana Supreme Court's decision in <u>Montana-Dakota Utilities Co. v. Bollinger</u>, 632 P.2d 1086 (Mont. 1981); (2) lack of available comparable data, and (3) flaws in the manner in which Dr. Wilson calculates a rate of return for the Bridger Mine.

63. In making this decision, the Commission found weaknesses in both approaches used to determine the captive coal expense. The Company's "market approach" was fairly thorough. However, as explained on page 41 in Order No. 4714a of Docket No. 80.4.2, from the Department of Justice report "Competition in the Coal Industry":

> In practice, however, because of the nature of the coal markets, <u>identification of the appropriate competitive prices is virtually impossible</u>. Coal prices are not some broad national aggregate but are tied to very specific location and quality factors. In addition, a significant portion of the steam coal is sold by long-term contract. Thus it may prove difficult to estimate an appropriate set of market prices to use to check a utility's accounting price of coal. (emphasis added) (TR. pp. 47 & 48 of Docket No. 80.4.2)

One of the very prominent weaknesses in the market approach is that coal from outside areas of the generating units require varying degrees of transportation and related costs which can greatly distort the comparability of using shipped coal versus a minemouth operation. Although the market may show the economic advantage of a minemouth operation, the relative comparability of the coal prices may be forfeited because of inordinate, dissimliar costs such as transportation.

64. Dr. Wilson's "rate of return method" should have provided highly useful guidelines for determining a reasonable level of profitability for Bridger Coal Company. However, it is not clear from this record that MCC's determination of Bridger's overall return was consistent with the process used to determine the rate of return for the six available coal companies or the unregulated firms throughout the economy. Therefore, the Commission finds Dr. Wilson's proposed coal adjustment to be unacceptable in this Docket. The amount of MCC adjustment for captive coal disallowed in this docket is $93,000. (MCC Exh. 3, GFH-2, Sch. 4, p. 1 of 2)

65. The Commission stresses that this decision in no way determines a preference between the two methodologies in question, but rather, reflects the evidence presented in this particular case. As pronounced in the MDU v. Bollinger court case, the Commission reserves the right to determine the appropriate methodology for captive coal expenses.

Coal Expense

66. In order to comply with the Commission's Interim Rules, PP&L proposed an adjustment to general coal expense of $218,000 in their interim application to reflect the use of annual average cost. This adjustment was made to comply with the methodology approved by the Commission in the previous order, Order No. 4881a of Docket No. 81.8.70. MCC proposed no further adjustment to this account, indicating agreement with the calculation performed by the Company in making their interim adjustment:

> ... The adjustments underlying the revised request for interim rate relief conform to the procedures adopted by the Commission in PP&L's last rate case. (MCC Exh. 3, p. 2)

67. Concerning the computation of Centralia and Dave Johnston coal prices for purposes of its general rate case filing, Mr. Watson testified:

> The cost per ton amounts relied upon were based on actual prices during the fourth quarter of 1981. In light of the fact that these prices will be over a year old at the time new rates associated with this proceeding go into effect, I believe this represents a highly conservative approach to setting the price of coal for rate making purposes. (PP&L Exh. 22-T, p. 16)

Mr. Watson also supplied current cost information for Centralia, Dave Johnston and Wyodak plants in his rebuttal testimony (PP&L Exh. 22-T, Table 3).

68. In their reply brief, the Company proposed that the $218,000 adjustment for coal expense endorsed by Mr. Hess should not be allowed since updated coal costs show this adjustment to be inappropriate. In a letter received by the Commission on January 14, 1983, MCC agreed with the Company's position that to update coal costs would be consistent with the related treatment approved by the Commission in Order No. 4881a, Docket No. 81.8.70. Based on the costs shown on line 7 of Table 3 of Mr. Watson's rebuttal exhibits giving updated 12 month average coal costs,

MCC calculated that the amount of coal expense to be conceded in this proceeding is $176,000. The Commission finds that the Company's updating of annual average coal costs is consistent with the methodology approved in Order No. 4881a, Docket No. 81.8.70. The Commission further finds that the calculation performed by MCC in their aforementioned letter best represents the methodology approved by the Commission in Order No. 4881a. The Commission, therefore, determines that $176,000 of the proposed $218,000 adjustment for general coal expense is inappropriate and not allowed in this proceeding.

Pro Forma Interest

69. In its calculation of interest expense the Company excludes interest on construction funds. MCC witness Hess seeks to include interest on construction through the use of a pro forma interest computation. The Company argues that those interest deductions should be carried to the future to offset the expense of the plant going into service. The Commission is persuaded that interest on construction is deductible for income purposes and should be included in the calculation of interest. The result of the pro forma interest adjustment, as approved by the Commission, is a $28,000 reduction of State Tax and a $180,000 reduction of Federal Tax.

Restoration of Unused Investment Tax Credits

70. The Company proposes to restore investment tax credits on a modified flow-through basis over an eight year period. MCC witness Hess on the other hand advocates a flow-through of one-half of the investment tax credits that can be utilized in the test year after adjustment for any rate increase authorized. The Company argues that their approach meets the goals of capital formation and passes some of the benefits to future rate payers. Hess takes the position that in an environment where net plant is always growing, there is no reason to defer the recognition of these benefits. The Commission, after a careful review, finds no reason to modify its treatment of investment tax credit restoral (two-year flow-through as advocated by Mr. Hess) as adopted in Order Nos. 4771a and 4881a. The amount of the approved investment tax credit adjustment is calculated to be $518,000.

Attrition

71. Mr. Watson submitted testimony developing in general terms the primary factors which have given rise to earnings attrition for the Company and developing the attrition study the Company is sponsoring in this application. Concerning why PP&L is requesting an attrition adjustment in this case, Mr. Watson testified:

> While one of the Commission's goals is to allow the Company a reasonable opportunity to achieve its allowed rate of return, the process relied upon in the past for the most part, has not provided that opportunity .... The Company's total utility earnings per share, excluding AFUDC, have declined significantly over a ten-year period...in spite of significant cost reduction efforts and numerous rate increases in all jurisdictions. (PP&L Exh. 8-T, pp. 2-3)

72. Mr. Watson viewed attrition as a problem in the electric utility industry as a whole and blamed it on factors such as (1) unprecedented levels of inflation, (2) growth in plant at higher than embedded costs, (3) decreases in or elimination of economies of scale, (4) increases in uncontrollable costs, and (5) increased costs of capital. (PP&L Exh. 8-T, pp. 3-4)

73. Concerning Commission allowance of interim increases and pass through of specific cost increases, Mr. Watson testified, "While these procedures have been helpful, specific cost pass through increases and interim increases tied to previous orders do not measure all cost increases, even at the time of the filing, so earnings attrition is still a significant problem." (PP&L Exh. 8-T, p. 6)

74. Mr. Watson discusses the general approach he used in performing the Company's attrition study:

> The general approach taken was to analyze the changes expected between the test period and the attrition year as those changes impact operating costs, revenues, and rate base. The attrition year chosen was the twelve months ended December 31, 1983 based on the assumed receipt of an order in this current application in December, 1982.... The starting point was the result of operations at proposed rates as shown on Table SEP 4-11. From the starting point, I applied specific growth factors derived from my analysis of 10 years of data for each specific rate making item. I utilized judgment in my choice of growth rates as well as my knowledge of specific events to develop what I

> believe to be a reasonable attrition allowance to be applied to the test year. (PP&L Exh. 8-T, pp. 7-8)

75. Based on the results of his study (including financial attrition), Mr. Watson determined the additional test year revenue requirement due to attrition to be $2,463,000. (PP&L Exh. 8-T, p. 14)

76. MCC witness Dr. Wilson examined PP&L's growth in assets, revenues, and earnings in recent years and determined there to be little existence of attrition. The results of his study "clearly show that over this period net income and revenues increased at a faster rate than plant (MCC Exh. 1, p. 15)." Dr. Wilson also examined PP&L's operating ratios and rate of return data, and he testified:

> PP&L's 1981 operating ratio (operation expenses in relation to operating revenues) was the lowest that it has been in recent years. Likewise, the Company's 1981 rate of return on total capitalization and its rate of return earned on common equity were the highest that they have been in five years.... PP&L's operating revenue per $100 of plant investment has increased substantially over the past five years and average plant investment per dollar of net operating income has declined. (MCC Exh. 1, pp. 15-16)

77. Dr. Wilson determines that an attrition adjustment in this proceeding would not be appropriate or necessary. He argues that PP&L's circumstances have improved in recent years and that PP&L is requesting a retroactive ratemaking adjustment, which "would constitute an immense efficiency disincentive and would undermine the fundamental nature of the rate of return allowance (MCC Exh. 1, p. 18)." Dr. Wilson contends that evidence of inflation does not establish attrition and that attrition allowances should not be made to offset adverse general business conditions:

> The impact of general business conditions is directly accounted for (and compensated for) in market-based rate of return allowances. To add an attrition allowance for general business conditions would, therefore, result not only in double compensation, but also in the shedding of all risks by the utility to its ratepayers.... The market will reflect anticipated attrition (when and if it is anticipated) in the price paid for utility common stock. Consequently, cost-of-capital studies, such as DCF analysis, which are premised upon market conditions, tend to automatically account for anticipated attrition effects. That is so because attrition anticipations which suppress stock prices thereby result mathematically in higher dividend yields and, in turn, in higher

allowed revenues than if no attrition anticipations had existed and dividend yields had been lower. (MCC Exh. 1, pp. 23, 30-31)

78. After very careful analysis of the testimony and data in this docket, the Commission determines that an attrition allowance should not be allowed. The Commission questions some of the "known and measurable" qualities in the Company's study which looks forward to 1983 projected data. The Commission feels that its pass through of specific costs and make-whole interim policies greatly work against the encroachment of earnings attrition. Considering the fact that PP&L filed this application before the order in Docket No. 81.8.70 was issued, the Commission feels that an inadequate amount of time has passed to conclude what return PP&L will realize under the provisions of Order No. 4881a. The Commission also emphasizes that the rates of return granted in orders afford PP&L the opportunity to realize those returns, and the granting of an attrition allowance in this docket could provide some management disincentive to realize the granted rate of return. The Commission, in making this decision, is not ruling out the possibility that an attrition adjustment could be justified under the proper circumstances, but in this proceeding an attrition adjustment is inappropriate and not allowed.

79. The following table shows that additional annual revenues in the amount of $2,683,000 are needed by the Applicant:

PACIFIC POWER AND LIGHT COMPANY

Pro Forma Results of Montana Electric Operations
at Present Rates and Additional Revenue
Required to Produce 10.97% Rate of Return; 1981 Test Year
(000)

	Company Per Books Adjusted	Company Adjustments For Interim Plus MCC Adjustments	Commission Adjustments	Accepted Pro Forma	Increase Required to Produce 10.97% Return	Total
Operating Revenues	$23,180	$ 464	$ -0-	$23,644	$ 2,683	$26,327
Operating Revenue Deductions						
Operating Expenses	$14,035	$ (154)	$ 269	$14,150	$ 10	$14,160
Depreciation and Amortization	2,461	-0-	-0-	2,461	-0-	2,461
Taxes Other Than Federal Income	1,236	-0-	-0-	1,236	2	1,238
State Income Tax	43	35	(18)	60	181	241
Federal Income Tax @ 46%	275	360	(115)	520	1,149	1,669
Investment Tax Credit	(247)	(325)	104	(468)	(1,034)	(1,502)
Net Federal Income Tax	$ 28	$ 35	$ (11)	$ 52	$ 115	$ 167
Deferred Income Taxes	288	(169)	-0-	119	-0-	119
Income Taxes Deferred in Prior Years	(78)	-0-	-0-	(78)	-0-	(78)
Investment Tax Credit Adjustment	235	40	(52)	223	518	741
Amortization of Proceeds from Sales	-0-	(202)	-0-	(202)	-0-	(202)
Total Operating Revenue Deductions	$18,248	$ (415)	$ 188	$18,021	$ 826	$18,847
Net Operating Income	$ 4,932	$ 879	$ (188)	$ 5,632	$1,857	$ 7,480
Average Rate Base	$71,067	$(2,648)	$ 26	$68,445	$ (259)	$68,186
Rate of Return	6.94%			8.22%		10.97%

E. RATE DESIGN

80. Cost of Service. The Applicant (Harris, Exh. 10-T) proffered a Long-Run Incremental Cost (LRIC) study as the basis for determining cost of service. The LRIC in this filing employs the same general methodology submitted in the 1981 rate proceeding (Docket No. 81.8.70), but is "updated to incorporate the Applicant's current estimates of incremental costs, annual carrying charges, plant capacity factors and customer load class system diversified load factors" (Exh. 10-T, p. 1)

81. The Montana Consumer Counsel did not sponsor testimony on either the LRIC study or rate design issues in this filing.

82. Whereas previous LRIC studies computed an average total annual revenue requirement for peaking facilities, using a combustion turbine and a pumped storage facility, the 1982 LRIC study excludes the latter peaking resource. This decision is based on the Applicant's determination that a pumped storage facility is no longer an available resource option for meeting peak demand (See Applicant Data Response to Commission Staff data request No. H-7).

83. A second revision pertains to transmission costs. Although the Applicant computes the annual revenue requirement for incremental generation resources on the basis of three different baseload facilities, i.e. Colstrip Nos. 3 and 4, WPPSS No. 3 and Wyodak No. 2, the Applicant's incremental Transmission Investment and Wheeling Expense calculation excludes the latter Wyodak facility. This decision results from the ability of the Wyodak facility to tie-in with existing transmission facilities (See Applicant Data Response to Commission Staff data request No. H-1).

84. Finally, the Applicant has made an "improvement" to the method used to convert investment dollars into annual recurring charges. In Docket No. 81.8.70 a levelized fixed charge was applied to transmission and generation related investments; in this Docket the Applicant applied an annualized fixed charge. The Applicant's basis for this charge is that during inflationary times the levelized fixed charge overstates the actual cost; that is, while the levelized fixed charge accounts for all fixed charges assessed against capital equipment it does not account for the savings that result from avoiding a year's worth of inflation.

85. While the Commission approves of the above changes to the LRIC methodology, it finds need for an exhaustive accounting of Street and Area Lighting Long-Run Incremental costs. The current LRIC only includes generation and transmission related costs for the existing seven lighting schedules: clearly, distribution costs also exist. To partially correct this shortcoming in the current LRIC, the Applicant proposed to monitor installation costs for three lighting schedules and to study the revenue requirements of a standardized high-pressure sodium-vapor street-lighting plant. The Commission, however, questions the cost effectiveness of monitoring the installation costs of lighting schedules that the Applicant also proposes to grandfather. Finally, the Applicant is directed to provide an analysis of distribution and billing related costs for street and area lighting tariffs in the Applicant's next rate proceeding; the objective of such analysis is to develop fully compensatory rates for these customers.

86. Schedule 1 below summarizes the existing and final LRIC cost of service. The rates in this schedule would, however, generate revenues in excess of the approved level and consequently must be altered. The Commission approves of the Applicant’s rate spread goal which obtains from each customer class revenues equal to a uniform percent of long-run incremental costs. It remains to establish a rate design that generates the approved level of revenues.

SCHEDULE 1

SUMMARY OF LONG-RUN INCREMENTAL COSTS[1]
AT GENERATOR (1982 $)

Voltage Level/ Customer Class	Energy (¢/KWH)[2]	Demand Related On-Peak Hours ($/KW)[3] Winter	Demand Related On-Peak Hours ($/KW)[3] Summer	Commitment and Billing Related ($/Customer/Month)
Primary/Secondary:				
Residential	4.85	65.1	13.5	14.05
Small General Service	4.85	79.2[4]	27.6[4]	18.55[4]

Large General Service	4.85	56.4	4.8	141.0
Irrigation	4.85	51.6	Unknown	466.0[5]
Street and Area Lighting	4.85	51.6	Unknown	*[6]

1 From Exh. 10-T, Table LGH 5-12. Note these results are at generation level rather than at meter; consequently, line losses are excluded.

2 When line losses are included the rate increases to about 53 mills with a variance of less than 2 mills.

3 Comprised of Generation, Transmission and Distribution related demand costs.

4 Computed as a weighted average of the number of customers in three subclasses.

5 Includes distribution related demand costs.

6 Not included in LRIC.

87. Rate Design. The Applicant’s proposal was stated by Mr. Sloan:

> Q. Once the increased revenue goals for each class were determined, how were the rate schedules modified to recover the additional revenue?
>
> A. For those rate schedules which do not have separate Energy Charges and Demand Charges, the Energy Charge portion of the rate was increased so as to obtain the required additional revenues. For those general service schedules which have separate Energy Charge and Demand Charge components, both of these rate components were increased on approximately a uniform percentage basis in order to recover the additional class revenues. Additionally, in those schedules which currently contain pricing differentials between winter and summer usage, this seasonal differential has been maintained. (Exh. 11-T, p. 5)

88. The Commission questions the merit of such a proposal which ignores the additional information provided by the 1982 LRIC. That is, the relative importance of components of the LRIC is not static over time. Although existing rates do not strictly reflect the results of the 1981 LRIC study, the Commission finds that future rates should, to the maximum extent possible, reflect the results from the Applicant's most recent LRIC study.

89. Although the Commission disagrees with the Applicant's rate and rate design proposal a strict application of the LRIC is not problem free, e.g. see the discussion infra on LRIC based General Service and Industrial demand charges. In this Docket the Commission seeks to balance the usefulness of economic cost information from the LRIC study with objectives of rate stability and customer impact concerns. The following sets forth the Commission's rate design decisions.

90. Residential. The Commission finds that the existing rate structure is to be retained including the intrablock and seasonal differentials for energy. Schedule 2 provides estimates of the final rates.

SCHEDULE 2

RESIDENTIAL RATE DESIGN (1982 $)[1]

Energy (¢/KWH)	Summer	Winter
1st Block	3.019	3.019
2nd Block	4.445	4.445
Tail Block	5.65	6.216
Minimum Bill[2]	2.75/month	

1 These rates are based on an assumed final level of revenue generation equal to $22,250,000 comprised of $19,206,000 (pre-interim test year revenues), a $539,000 increase (Docket No. 82.9.59) and $2,505,000 (Docket No. 82.4.28).

2 The minimum bill results from the 1982 LRIC and is invariant with respect to the final approved increase in Docket No. 82.4.28.

91. General Service. The two existing General Service (GS) schedules (22 and 24) feature seasonally differentiated energy (for demand costs) and demand charges and a minimum bill charge. A strict interpretation of the LRIC, however, would result in a flat energy rate, seasonally differentiated demand charges and a minimum bill.

92. The Commission finds necessary a change to the existing rate design and rates. First, each of Schedules 22 and 24 shall feature two distinct sets of rates, one for demand metered and another for nondemand metered customers, as demonstrated in Schedule 3. The demand

metered rate shall feature seasonally differentiated demand charges and a flat energy charge. The summer and winter demand charges shall equal $1.50 and $2.25 respectively; the Commission prefers to tariff these demand charges in lieu of those from a strict interpretation of the LRIC study because of the potential negative customer impact from increasing the winter demand charge by an eye opening 800 percent [the LRIC study generates demand charges equal to $1.57 (summer) and $8.82 (winter)]. The minimum bill charge should be reduced to $2.65 from the existing $4.81 level; the $2.65 charge reflects the results from the Applicant's LRIC study. The nondemand metered rate shall feature the same minimum bill charge as for the demand metered rate. The energy rate, however, shall be seasonally differentiated with a winter rate equal to 110 percent of the summer rate; the accuracy of this differential will be investigated in the Applicant's next rate proceeding.

SCHEDULE 3

ILLUSTRATIVE GENERAL SERVICE TARIFF SHEET

	Winter	Summer
Demand Metered		
Energy (¢/kwh)	3	3
Demand ($/kw)	2.25	1.50
Minimum Bill ($/mo)	2.65	2.65
Nondemand Metered[1]		
Energy (¢/kwh)	3.17486	2.88624
Minimum Bill ($/mo)	2.65	2.65

1 Note these rates maintain the 10 percent seasonal differential and generate the same revenues as the combined energy and demand rates for the Demand Metered Customer.

93. Agricultural Pumping. Presently, irrigation customers are served on a separate schedule which features seasonally differentiated energy and demand charges and a minimum bill. The Applicant proposed no rate design changes to this schedule, proposing only to increase energy and demand charges by an equal percent to recover increased cost of service. A strict interpretation

of the LRIC study, however, would result in a flat energy rate and a minimum bill charge that recovers both distribution, billing and demand related costs (See Exh. 10-T, Table LGH 5-7).

94. While preferring a strict interpretation of the LRIC study, the Commission finds the results of such a decision unsatisfactory; the LRIC study does not generate demand related costs although these costs clearly exist. The Commission directs the Applicant to eliminate Schedule 36. Such a proposal was made by the Applicant in Docket No. 81.8.70 (See Order No. 4881a). Those customers currently served on Schedule 36 shall now be served on Schedule 24 under the appropriate demand/nondemand metered tariff; Schedule 24, however, must contain a separate minimum bill for irrigation customers equal to $112.60. Relative to the current General Service load class demand charge, this minimum bill recognizes the additional distribution and billing related costs for the irrigation load class.

95. Large General Service. The current rate design for this class features a flat energy rate, seasonally differentiated demand charges and a minimum bill. The Applicant proposed no change to this rate design, but recommends an equal percent increase to energy and demand charges to recoup the increased revenues. A strict interpretation of the LRIC study, however, would result in a 72 percent reduction in the summer demand charge (from the existing $1.30/kw rate) and a 144 percent increase in the winter demand charge.

96. The Commission finds the customer impact of the LRIC demand charges undesirable and directs the Applicant to retain the current seasonal demand charges. The minimum bill, however, shall equal $46.25, down from the current $134.38 -- a result of the 1982 LRIC; the flat energy rate shall reflect the balance of the tempered LRIC revenue responsibility.

97. Street and Area Lighting. For the seven street and area lighting schedules the Applicant proposed the following (See Exh. 11-T, pp. 5, 6). First, as with previous Dockets, the Applicant proposes to obtain from the energy related portion of these schedules an amount equal to a uniform percent of the LRIC for energy. An exception is with Schedule 54 where the seasonal demand charges are also increased. Minimum bills were not changed. Second, due to the availability of yard lighting kits for home installations, the Applicant proposes to grandfather service on

Schedules 14 and 15 to existing customers. Finally, the Applicant proposed to add an additional rate for 9,500 lumen lights to Schedule 51.

98. The Commission generally approves of the Applicant's proposals noting the following. First, the method of recovering the increased revenue responsibility is approved. As with Schedules 22 and 24, the Commission directs the Applicant to develop two separate rates for Schedule 54 customers -- one for demand metered and the other for nondemand metered customers; Finding of Fact No. 92 above provides a discussion of the appropriate rate design. The rates, however, shall otherwise equal the Applicant's proposed. The Commission finds merit in and approves of the Applicant's proposal to grandfather service on Schedules 14 and 15 and to add the additional lumen rating to Schedule 15.

99. <u>Rate Design Policy</u>. To facilitate verification of tariffs and to speed up implementation of interim and final revenue increases, the Applicant is directed to follow the below procedures in future rate proceedings. First, interim revenue increases shall be achieved by applying a uniform percent increase to <u>all</u> rates and charges. The final approved increase, however, will likely be based on true ups to cost of service based rates per the LRIC results as modified by the Commission. Additional revenue adjustments shall be accounted for in the final true up, e.g. reactive power and demand charge rate and rate design changes in this Docket.

100. Second, each tariff submittal made by the Applicant must include billing determinants for existing and final rates (or interim) summed up indicating existing and final (or interim) revenues. The billing determinant data must be exhaustive including seasonal demand and energy consumption, Minimum Bill and reactive power units of consumption for each schedule. Working papers providing analysis of the revenue effect must accompany the Applicant's tariffs.

<u>CONCLUSIONS OF LAW</u>

1. The Applicant, Pacific Power and Light, furnishes electric service to consumers in Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. MCA § 69-3-101.

2. The Commission properly exercises jurisdiction over the Applicant's rates and operations. MCA § 69-3-102, and MCA, Title 69, Chapter 3, Part 3.

3. The Commission has provided adequate public notice of all proceedings and opportunity to be heard to all interested parties in this Docket. MCA Title 2, Chapter 4.

4. The rate level and rate structure approved herein are just, reasonable, and not unjustly discriminatory. MCA § 69-3-330.

ORDER

1. The Pacific Power and Light Company shall file rate schedules which reflect increased annual revenues of $2,683,000 in lieu of, rather than in addition to, interim rates. The total annual revenues of Pacific Power and Light Company will be approximately $26,327,000.

2. The increased rates authorized herein shall be effective upon the filing and approval of revised tariffs consistent with this order.

3. Rate schedules filed shall comport with all Commission determinations set forth in this Order.

4. Pacific Power and Light Company’s final rate calculations are to be supported by detailed working papers showing: (1) test year sales per Schedule for each season and rate; (2) Docket Nos. 82.4.28 and 82.9.59 final rates; and (3) the product of (1) and (2) mentioned herein, summed, equaling the total revenue requirement, less the existing revenue requirement.

5. The Applicant's tariff submittal shall reflect the current BPA Exchange Credit for the qualifying schedules.

6. All motions and objections not ruled upon are denied.

DONE AND DATED this 24th day of January, 1983 by a vote of 4-0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

CLYDE JARVIS, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Madeline L. Cottrill
Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten days. See 38 2.4806, ARM.

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